

BC hydro

Capability of the
Interior to Lower Mainland
Transmission System

Kelly Lake to
Cheekye Substation
Second 500 kV
Transmission Line

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CAPABILITY OF THE INTERIOR TO LOWER MAINLAND TRANSMISSION SYSTEM

1. SUMMARY

The Interior to Lower Mainland portion of B.C. Hydro's major transmission network requires reinforcement by the Fall of 1995, based on the September 1990 probable load forecast and the November 1990 resource plan.

The Interior to Lower Mainland transmission network supplies the Lower Mainland and Vancouver Island. The need for transmission system reinforcement results from continued load growth in these two regions together with the location of major resources to meet this demand in the northern and eastern parts of the province.

Without the necessary reinforcement, (a) the system would be exposed to an unacceptable risk of widespread system blackouts due to voltage collapse, (b) the system would need to be operated in a restricted manner to minimize the chance of a major system blackout and (c) the system efficiency would be reduced by the constraints necessary to maintain system security.

2. INTRODUCTION

The purpose of this report is to describe investigations into the capability of B.C. Hydro's Interior to Lower Mainland transmission system with existing and committed projects (American Creek series capacitors in 1990-1991 and Dunsmuir Static Var Compensator in 1993). The assessment of options for reinforcing the Interior to Lower Mainland transmission system is the subject of other investigations and is outside the scope of this report.

The present B.C. Hydro major transmission network is shown in Figure 1. The Interior to Lower Mainland major transmission network, shown in Figure 2, consists of the transmission system connecting the Kelly Lake and Nicola substations, in the Interior, to each other and to the Ingledow, Meridian and Cheekye substations in the Lower Mainland. These three major receiving stations serve the Lower Mainland and Vancouver Island. The four Interior to Lower Mainland 500 kV transmission lines (circuits 5L42, 5L41, 5L81 & 5L82) are approximately 50% series compensated to provide increased transfer capability.

The major supply to Vancouver Island is from Cheekye substation via the Cheekye-Malaspina-Dunsmuir overhead and submarine cable 500 kV transmission system (2x1200 MW capacity cable circuits to V.I.). There is also a 1050 MW capacity connection from the Lower Mainland to the south end of Vancouver Island. This additional connection is supplied from the Arnott substation via two 138 kV AC cable circuits (250 MW capacity) and a +260/-280 kV HVDC (800 MW capacity) system.

3. LOAD GROWTH AND RESOURCE PLANS

The Interior to Lower Mainland transmission system is expected to require continual reinforcement because load growth in the Lower Mainland and Vancouver Island regions is expected to be supplied primarily by generation additions, including IPPs, located outside of these two regions.

Approximately 70% of B.C. Hydro's integrated system load is located in the Lower Mainland and Vancouver Island regions (45% in the Lower Mainland and 25% on Vancouver Island). The September 1990 probable load forecast for B.C. Hydro's integrated system (I/S) is provided in

Table 1. It shows that, even after accounting for the effects of PowerSmart and other demand side management (DSM) programs, the B.C. Hydro load is expected to increase by 1040 MW from 1990/91 to 1995/96, an average growth rate of 210 MW per annum. The total Lower Mainland and Vancouver Island portion of this 5 year load growth is expected to be 730 MW.

Over 85% of the generation additions required to supply the 1040 MW growth in the B.C. Hydro integrated system load are remotely located from the major load centres in the Lower Mainland and Vancouver Island regions. Hence, a need to reinforce the transmission system supplying these regions can be expected within the next five years.

The first major generation plant which will be added to the B.C. Hydro integrated system is Alcan's Kemano Completion project (KCP) located in northwestern B.C.. It will add 520 MW of generating capacity in late 1994 or early 1995 to supply B.C. Hydro's integrated system load growth most of which will occur in the Lower Mainland and Vancouver Island regions.

To integrate the Kemano Completion generating plant requires reinforcement of various parts of the B.C. Hydro transmission system. The third Williston to Kelly Lake line, approved for construction by the Provincial Government, is planned for service in Fall 1994. It is one major transmission system addition required to securely and efficiently integrate remote generating plants like KCP into the B.C. Hydro transmission network and bring power from remote northern plants down to Kelly Lake substation in the Interior. Reinforcement of the Interior to Lower Mainland network is required to bring this northern power further down into the major load centres in the Lower Mainland and Vancouver Island regions.

In the long term, most of the resources required to meet the growing demand for electricity in the Lower Mainland and Vancouver Island regions will continue to be supplied from generating plants located outside these regions as the indicated by the resource plan provided in Table 2. The location of major generating plants outside these major load areas will continually increase the loading on the existing Interior to Lower Mainland transmission network and thus require its continual reinforcement.

4. STUDY SYSTEM

The system configuration used in the studies of transmission system capability was based on the 1994/95 stage of system development shown in Figure 3. The powerflow base case used in the studies is described in detail in Appendix A. Normal operation of Burrard Thermal generating plant is assumed (ie four units operating as synchronous condensers and the remaining two units shut down).

5. SYSTEM PERFORMANCE AND METHODOLOGY

The capability of bulk transmission systems to transmit power over long distances can have a variety of limitations. These include transient and dynamic electromechanical stability, voltage stability and thermal capacity of the lines. B.C. Hydro's Interior to Lower Mainland transmission system is now normally limited by voltage stability but the other limitations would also come into force if system reinforcements are delayed.

Voltage instability is the collapse of the voltage at the receiving end of a transmission system caused by overloading of the transmission system and resulting in either widespread blackouts or large areas of very low voltages. Voltage instability could occur following the loss of one or more major transmission system components (eg transmission lines or transformers).

The studies undertaken to determine when the Interior to Lower Mainland transmission system requires reinforcement were based on single-contingency security criteria. The limiting criterion

for the Interior to Lower Mainland section of the major transmission network is voltage stability which is part of the following general criteria:

For any given stage of system development, load growth or modification of generation or transmission facilities, it must be shown by simulation studies that, during peak load or other high-stress conditions, the network retains electromechanical stability and voltage stability following first contingency disturbances. In these studies the strength of the network is tested to see if the system will remain stable following a fault with one unsuccessful reclosure at the most critical point without resort to generator or load shedding. Both three-phase faults cleared in normal time and single-phase faults cleared after a delay due to breaker failure are studied. The worst result governs. As well, adequate voltage stability margins must be maintained at critical buses.

The method used by B.C. Hydro to assess voltage stability margins in the Interior to Lower Mainland transmission network is based on measuring reactive power margins at several key major receiving stations following the outage of a major transmission line. A detailed description of the voltage stability criteria and methods used in the studies upon which this report is based is provided in Appendix B.

The critical system conditions studied when evaluating the capability of the Interior to Lower Mainland portion of the B.C. Hydro transmission system can be divided into two groups:

1. Peak load conditions during which the Peace and Alcan generating plants and any independent power producers (IPPs) north of Kelly Lake substation are operating at their maximum capacities and,
2. Peak load conditions during which the Columbia generating plants and any IPPs east of Nicola substation are operating at their maximum capacities.

With the Peace and Alcan generating plants operating at their maximum capacities, the western side of the B.C. Hydro major transmission system is heavily loaded. The most onerous single contingency under these conditions is an outage to one of the major transmission lines on the western side of the system. The loss of the existing 500 kV transmission line between Kelly Lake and Cheekye substations is usually the most critical outage for voltage stability under these conditions.

With the Columbia generating plants operating at their maximum capacities, the eastern side of the B.C. Hydro major transmission system is heavily loaded. The most onerous single contingency under these conditions is an outage to one of the two 500 kV circuits from Nicola substation to the Lower Mainland, circuit 5L81 (Nicola to Ingledow) or circuit 5L82 (Nicola to Meridian). Since these two circuits are very nearly the same length and carry approximately the same load under normal conditions, the loss of one of them has approximately the same impact as the loss of the other.

6. STUDY RESULTS

Technical studies demonstrate that the 1994/95 stage of B.C. Hydro transmission system development is adequate to supply the Lower Mainland and Vancouver Island loads up to a total level of 6110 MW. This level is expected to be exceeded in the winter of 1995/96 when the total Lower Mainland and Vancouver Island peak load will probably be approximately 6300 MW. Details of the study results are provided in Appendix C.

The range of forecasts for the Lower Mainland/Vancouver Island (LM/VI) load from the low forecast to the high forecast is shown in Figure 4. The 6110 MW LM/VI load limit is also shown

on Figure 4. Figure 4 indicates that reinforcement of the Interior to Lower Mainland transmission system would be required as early as 1993 for the high forecast growth rate and as late as the year 2002 for the low forecast growth rate. This large variability in the need for transmission system reinforcement supports the strategy of providing flexible transmission system reinforcement plans.

SENSITIVITY STUDIES

The load level at which reinforcement is required is sensitive to quite a number of parameters. The results of investigations into the sensitivity, to changes in some of these parameters, of the transmission system capability are shown in Figure 5. Figure 5 plots the changes in the LM/VI load limit, compared to the base case, resulting from various changes in the configuration of the system.

Two values are plotted in Figure 5 for each system configuration change. One value corresponds to the load limit for conditions of maximum Peace/Alcan generation and the other corresponds to the load limit for conditions of maximum generation from the Columbia plants.

The base system, Case A, to which each study is compared is the 1994/95 stage of system development but without any IPPs in the Lower Mainland or on Vancouver Island. The 6110 MW LM/VI load limit mentioned earlier is based on Case B of Figure 5 in which a 122 MW IPP was added at the Burrard station near Port Moody.

Case B (122 MW LM IPP): About 150 MW of self generation, with a winter dependable capacity of 122 MW, is expected to be added in the Lower Mainland and Vancouver Island regions in the mid 1990's. Because the exact locations of these LM/VI IPPs are presently uncertain, this resource was represented in the studies as a 122 MW output from the Burrard synchronous condensers. The increases shown in Figure 5 for the LM/VI load limit are 83 MW and 98 MW for conditions of maximum Peace and maximum Columbia generation respectively.

The LM/VI load limit increases by less than the 122 MW of additional Lower Mainland generation, in this case, because:

- (a) Representing the 122 MW LM/VI IPPs as a 122 MW power output from the Burrard synchronous condensers (S/Cs) would not provide any additional dynamic reactive reserves.
- (b) Only 122 MW of real power was added; no additional reactive power was supplied. Scaling the LM/VI load down by 122 MW would result in reducing the reactive component of the load also.
- (c) Adding 122 MW of generation at Burrard, which is quite close to the major transmission system, would not have the added benefit of reduced subtransmission system real and reactive power losses that scaling the LM/VI loads would.

Cases C & D (Addition of Remote Generation): Figure 5 demonstrates the effect that the addition of remote generating plants has on the LM/VI load limit. In Case C, the addition of a fifth 461 MW generator at the Revelstoke generating plant increases the loading on the Nicola to Lower Mainland lines making an outage to one of these lines, during conditions of maximum Columbia generation, more onerous than before. Figure 5 indicates that the LM/VI load limit is reduced by more than 100 MW under these conditions whereas the limit for maximum Peace conditions remains essentially the same.

Similar results are shown for Case D, the case of additional generation north of Kelly Lake, except that the limit for maximum Peace conditions is reduced with the limit under maximum Columbia conditions remaining essentially the same.

Case E (Importing from the USA): Importing power from the USA into Inglewood over the 500 kV BCH-BPA intertie increases the LM/VI load limit but Case E demonstrates that the increase is much less than might be expected. Case E indicates that importing 450 MW from the USA increases the LM/VI load limit for both maximum Peace and maximum Columbia conditions but the increase is less than 120 MW in each case. The increase is small because (a) the power imported from the USA, like in Case B described above, would not reduce the real and reactive power losses in the LM and VI subtransmission systems and (b) importing from the USA increases the loading on the USA system thus reducing the reactive support available for outages in the B.C. Hydro system.

Case F (LM-VI Generation Level): In general, when the outputs of the Lower Mainland, Vancouver Island and Bridge River generating plants are lowered, the loading on the Interior to Lower Mainland transmission system increases. This is because more of the Lower Mainland and Vancouver Island load must be supplied over the transmission network from remote generating plants.

Reducing the generation from the Lower Mainland, Vancouver Island and Bridge River hydroelectric plants by 200 MW (with no change in Mvar capacity), from 1140 MW to 940 MW, results in a 120 to 130 MW reduction in the LM/VI load limit as indicated in Figure 5.

The 1140 MW level of total output from the LM, VI and BR plants used in the base case is slightly greater than 75% of the maximum capacity of these plants. These plants are not modelled as operating at their full 100% capacity in the studies because there can be great variability in the output level of the Lower Mainland, Vancouver Island and Bridge River generating plants. Many of these plants, with the exception of the two Bridge River plants (520 MW total capacity), have quite limited storage reservoirs. Hence, in dry periods, there may not be enough water to "peak shave"¹ effectively with these plants. In addition, these plants are among the oldest in the system and therefore can be prone to lengthy repair outages. The 1140 MW level is presently considered representative of the dependable winter capacity of the total generation in the Lower Mainland, Vancouver Island and Bridge River regions.

Case G (Burrard Generation): Running the Burrard Thermal generating plant, which is located near Port Moody, during peak load periods would reduce the loading on the Interior to Lower Mainland transmission system. Presently four of the six generators at the Burrard Thermal generating plant are capable of operating as synchronous condensers (the steam turbines are uncoupled from the generators). They are normally used in that mode to provide dynamic reactive power reserves except when operating these units in the power generation mode is either necessary or economically beneficial.

Running the remaining two non-synchronous condenser Burrard units at their maximum of 150 MW each would increase the LM/VI load limit by 435 MW and 475 MW for maximum Peace and maximum Columbia generation conditions respectively as shown in Figure 5. Part of the increase in load limit is due to the additional reactive reserves provided by the two additional Burrard units (see Case I below).

Case H (Rescheduling USA Generation): Changing conditions in the USA system (which is outside B.C. Hydro's control) can have a significant effect on the LM/VI load limit. To provide an

¹"Peak shave" in this case means to operate the LM, VI and BR plants at high output levels during peak load periods to reduce the peak load (peak shave) on the transmission system supplying the LM/VI loads.

indication of the sensitivity of the LM/VI load limit to changes in the configuration of the USA system, a study involving rescheduling of USA generation was conducted.

Shutting down the 1280 MW Centralia plant near Tacoma in Washington state and replacing this lost generation by increasing the outputs of all generating plants in the Pacific Northwestern USA system west of Seattle/Portland by 4.9% reduces the LM/VI load limit by over 120 MW as indicated in Figure 5.

Case I (Operating BUT G5 & G6 in S/C Mode): Providing additional dynamic reactive power reserves by operating the fifth and sixth Burrard units as synchronous condensers (zero real power output) increases the LM/VI load limit by 210 MW and 237 MW for conditions of maximum Peace and maximum Columbia generation respectively. This case is the same as Case G except that, in this case, the two Burrard units are operated at zero real power output compared to 300 MW output for Case G.

Comparing Case I with Case G shows (for conditions of maximum Peace generation) that 210 MW of the 433 MW increase in LM/VI load limit provided by the addition of 300 MW of generation at Burrard is due to the additional dynamic reactive power reserve provided by the two additional generators. The remaining 223 MW increase is due to the addition of the 300 MW of real power at Burrard which is similar to the results shown for Case B.

This study was useful as a comparison to Case G but, presently, the fifth and sixth units at the Burrard Thermal plant are incapable of S/C operation. However, to provide additional dynamic reactive power reserves in the Lower Mainland, these two units can operate in a similar mode with the real power output from each unit maintained at the minimum operating level of 40 MW. This mode of operation of the Burrard Plant is relatively costly and securing firm gas purchases for this operation over the winter months is uncertain and may be difficult to obtain after 1993 when surplus capacity in the gas pipeline system will probably be used up for supply of gas to Vancouver Island.

Case J (Fraser Valley 300 MW Generating Plant): The results of this case illustrate the sensitivity of the LM/VI limit to where generation additions in the Lower Mainland are located. The data used for the generation addition in Case J is identical to that of Case G (running Burrard G5 & G6 at 300 MW). The only difference being that, in Case J, the 300 MW generating plant was connected to the 230 kV bus in the Atchelitz substation near Sardis in the Fraser Valley whereas, in Case G, the same 300 MW plant was connected to the 230 kV bus in the Burrard station near Port Moody.

Comparing the results of Case J (Atchelitz 300 MW plant) with Case G (Burrard 300 MW plant) indicate that the addition of 300 MW of generation at Burrard increases the LM/VI load limit about 40% more than the addition of an identical plant at Atchelitz. This is because Burrard is electrically much closer than Atchelitz to the 500 kV transmission system where most of the increase in reactive power losses occurs following a major transmission line outage. The dynamic reactive power reserve of a Burrard generator is thus better utilized than that of a similar plant located farther away from the major transmission system. These results indicate that the impact, on LM/VI load limit, of each IPP in the Lower Mainland and Vancouver Island regions should be evaluated individually.

7. CONCLUSIONS

Reinforcement of the Interior to Lower Mainland transmission system is required when the total Lower Mainland and Vancouver Island load reaches a level of 6110 MW which corresponds to a B.C. Hydro integrated system load level of 8700 MW. The current probable forecast indicates

that this level will be exceeded in the winter of 1995/96. Earlier reinforcement will be necessary if:

1. The Lower Mainland and/or Vancouver Island load growth rates exceed that of the current probable forecast.
2. Additional generating facilities are built outside the Lower Mainland and Vancouver Island regions.
3. The level of firm exports to the USA is increased.
4. The generation levels in the Lower Mainland, Vancouver Island and Bridge River areas over peak load periods cannot be dependably maintained above 1140 MW.
5. Firm imports from Alberta are negotiated.

8. RECOMMENDATIONS

The Interior to Lower Mainland transmission capacity is influenced by a multitude of demands, many of which are not controllable by B.C. Hydro. It is imperative that transmission system reinforcement plans have enough flexibility to be adjusted to reasonable, unforeseen capacity requirements in both the short and intermediate term. Therefore, the following are recommended:

1. Proceed with plans to reinforce the Interior to Lower Mainland transmission system based on the long term economics of meeting the probable load forecast.
2. Be prepared to proceed with short lead-time non-transmission alternatives to provide for higher than the forecasted probable load growth and for variances in resource plans.

B.C. Hydro's transmission planning strategy is to meet the load forecast utilizing projects with both short and long lead times. This will allow the flexibility to cater to changes in load growth rates, resource plans and other conditions without building excess transmission system capacity.

Long lead time projects (eg transmission lines) should be reassessed at each stage of their development to determine if, in light of changes in (a) load growth projections, (b) resource plans, (c) interchange agreements or (d) the economics of alternatives, it is prudent to delay or advance their subsequent stages. Before committing to the short lead-time projects, similar reevaluations should also be done.

APPENDIX A

**POWERFLOW
BASE CASE DESCRIPTION**

APPENDIX A: POWERFLOW BASE CASE DESCRIPTION

The major differences between the present (1990/91) system and the study system are:

- the B.C. Hydro integrated system load is 8700 MW in the base case study system. The September 1990 probable load forecasts for 1990/91 and 1994/95 are 7943 MW and 8687 MW respectively;
- a 600 MVA 500/230 kV transformer is in-service at Clayburn substation in the study system. Looping circuit 5L41 (Kelly Lake to Ingledow) into Clayburn substation and the provision of 500/230 kV transformation at Clayburn is presently planned for 1994.
- a -100/+200 Mvar static var compensator (SVC) is in service on the 132 kV bus at Dunsmuir substation in the study system. This SVC is presently planned for 1993.

Figure A1 is a powerflow one-line diagram of the base case used in this study. The system configuration in this powerflow case is basically the 1994/95 stage system configuration from the 20 November 1990 system plan except that the base case powerflow does not have any self generation represented in the Lower Mainland and Vancouver Island regions. Details of this powerflow case are:

- the BCH integrated system load is 8700 MW.
- the American Creek series capacitors are in-service (50% series compensation of each of circuits 5L81 and 5L82);
- the Columbia generating plants are operating at their maximum outputs;
- the Seattle City Light's Boundary generating plant is operating at 650 MW (62% of maximum);
- the Bridge River generation is operating at 394 MW (68% of maximum).
- the total output from the Lower Mainland hydroelectric plants is 333 MW (71% of maximum).
- the total output from the Vancouver Island hydroelectric plants is 411 MW (92% of maximum) with no generation at Keogh (the 2-unit, 54 MW, gas turbine plant is modelled with both units in their normal synchronous condenser mode).
- four Burrard synchronous condensers (S/Cs) are on-line producing a total of 100 Mvar in the predisturbance condition. The remaining two Burrard units which are not capable of synchronous condenser operation are shut down.;
- a 600 MVA 500/230 kV transformer has been added at Clayburn.
- the Nelway phase shifter is in-service at a fixed tap position selected to permit only 50 MW of BCH-USA counterclockwise loop flow.
- 675 MW import from Alcan.
- 228 MW exported to WKPL;

- 120 MW exported to USA.
- the ARN-VIT HVDC transfer level is 650 MW.
- both 138 kV AC cable ties to Vancouver Island are in service.
- both 500 kV AC cable ties to Vancouver Island are in service.

APPENDIX B

**B.C. HYDRO
VOLTAGE STABILITY
CRITERIA AND METHODS**

APPENDIX B: VOLTAGE STABILITY CRITERIA AND METHODS

When power is transmitted over long transmission lines, adequate reactive power support is required at intervals and the receiving end to maintain voltages. As power transfer increases, the voltage tends to sag at the receiving or load end of the transmission system. The load power (receiving end power or power transfer) versus load voltage (receiving end voltage) characteristic of such a system exhibits a limiting or abnormal condition where a small increase in power transfer causes excessive voltage drop and high currents at the load end.

B.C. Hydro's reactive power planning philosophy is to utilize switched shunt devices such as mechanically switched shunt reactors and capacitors to provide for the slow or planned variations in reactive power demands resulting from changes in such system conditions as (a) load levels, (b) generations schedules, (c) import and export schedules and (d) equipment maintenance outages. Dynamic reactive power sources such as generators, synchronous condensers (S/Cs) and SVCs are used to provide fast adjustment of reactive power supplies to cater to sudden unexpected outages to transmission lines and other equipment.

B.C. Hydro installs shunt capacitors at various locations in the system (a) to provide the reactive power demands of loads, (b) to maintain normal voltage levels throughout the system, (c) to maintain required dynamic reactive power reserves on generators, S/Cs and SVCs in preparation for transmission system equipment outages and (d) to reduce system losses.

SVCs and S/Cs are installed to maintain adequate voltage levels following contingencies on the major transmission system and to prevent voltage collapse or instability.

Voltage instability is defined as being manifested when a small increase in physical load (ie load admittance) results in such a large decrease in the load voltage that the total load power consumption does not increase, or even decreases.

Under conditions of heavy electrical demand and heavily loaded transmission lines an outage of a major system element (line or transformer or local generation) can lead to voltage instability and sudden collapse of voltages in the LM and VI region.

To assess voltage stability margins, B.C. Hydro utilizes the "QV curve" which determines the dynamic reactive power reserve at a specific "QV test bus". The steps comprising this technique are described in the following section entitled, "Voltage Stability Study Methodology" and the criteria applied to the study results are described in the section entitled, "Voltage Stability Criteria".

A. Voltage Stability Study Methodology

Voltage stability margins are assessed by producing a reactive-power-versus-voltage curve at a major receiving station bus. This curve is produced in the following manner:

1. Loads in the powerflow case are modelled as constant MV.A. That is, the real and reactive load on a bus is independent of the bus voltage. This load representation is used because (a) there is presently insufficient data to represent the loads in detail and therefore a conservative constant MV.A representation is necessary and (b) feeder voltage regulators and sometimes even distribution station on-load-tap-changing (OLTC) transformers, are often not modelled in the powerflow case for simplicity and to reduce computation times. This voltage regulating equipment (subtransmission and distribution substation feeder voltage regulators, OLTC transformers, etc) would maintain constant

voltages at load buses and hence loads would remain constant regardless of the voltages on the major transmission system.

2. A synchronous condenser is modelled at a major receiving station bus. This bus is designated the "QV test bus" since it is used to measure the dynamic reactive power margin. The reactive power output of this synchronous condenser is plotted as a function of its scheduled voltage. The scheduled voltage of this synchronous condenser is set to produce zero output in the initial pre-disturbance conditions.
3. After the disturbance occurs (eg a major transmission line is taken out of service including its associated line end reactor(s)), the reactive power output from the major receiving station synchronous condenser is plotted as its scheduled voltage (reference voltage) is lowered in small steps.
4. The resultant QV curve is used to assess voltage stability margins with respect to the minimum QV point which is the point of instability. This curve represents system conditions after OLTC transformers and voltage regulators have acted to restore loads to pre-disturbance levels and after automatic generation control (AGC) has restored area interchanges to pre-disturbance levels.

B. Voltage Stability Criteria

A typical QV curve is shown in Figure B1 and described below:

1. Q_R is the required reactive power margin. The required reactive power margin is proportional to the total real power (MW) transfer into the Lower Mainland. At least 4 Mvar of variable reactive power reserve must be provided in the Lower Mainland for each 100 MW of transfer into the Lower Mainland. The total flow into the Lower Mainland is determined by summing the pre-disturbance real power flows on all transmission lines into the Lower Mainland including the ties to the USA (if the pre-disturbance flow on these ties is into the Lower Mainland). With the 1994/95 B.C. Hydro system configuration this total flow into the Lower Mainland is determined by summing the flows on circuits 5L41 (KLY-CBN), 5L42 (KLY-CKY), 5L81 (NIC-ING), 5L82 (NIC-MDN), 2L90 (KLY-BRT), 2L91 (KLY-BRT), 5L51 (ING-CUSTR) and 5L52 (ING-CUSTR). Note that the flows on circuits 5L51 and 5L52 would only be included if the flow on these two circuits is towards ING. Flows towards Custer would not be subtracted from the sum of the flows on the other lines.
2. V_M is the maximum post-disturbance operating voltage. It is 2% less than the pre-disturbance voltage. This allows for a maximum voltage droop of 2% in the SVC characteristic. The required reactive power margin must be able to be provided without necessitating that the post-disturbance voltage be maintained above V_M (ie without requiring a voltage droop of less than 2%). If this is not possible then simply providing a reactive power source at the QV test bus cannot meet voltage stability criteria and other reinforcements (eg additional transmission lines or an SVC located elsewhere) are required.

The requirement of 4 Mvar per 100 MW of Interior to Lower Mainland transfer presently approximates an "n-2" criterion² (ie the loss of a line and the largest variable reactive power source). It is appropriate to make this margin proportional to the total transfer level and thus to require more margin as transfer levels increase. As transfer levels increase, more reactive power

²The "n" in "n-2" refers to the total number of elements in a system. An "n-2" criterion means that a certain level of performance must be met with two elements unavailable (ie the total number of system elements reduced to n-2).

sources would be added. More equipment would mean higher probabilities of multiple outages and hence the need for larger margins.

Some voltage "droop" in the SVC control action is necessary to ensure stable operation of the SVC under weak system conditions and to allow for some "deadband" in the control action if the SVC output varies in steps rather than continuously.

"Droop" can be defined as the change in voltage from zero output to full output. It is an indication of the slope of the SVC voltage/reactive power characteristic curve. The output of an SVC operating with 2% droop would change from zero to full output if the controlled bus voltage dropped by 2%.

The SVC voltage regulator can be provided with slow integral control to reduce the longer term droop to zero. That is, the SVC controls eventually reduce the voltage error to zero so that, in the longer term, the post-disturbance voltage of the controlled bus is raised to its pre-disturbance level if the reactive power limit of the SVC is not exceeded.

However, a very low transient droop cannot be provided because this would require a very high SVC voltage regulator gain. Setting this gain too high would cause instability of the SVC voltage regulator especially under weak system conditions. Therefore, the need for droop in the operation of an SVC is especially true during the initial transient period. Since the load characteristics are very uncertain, the QV curves produced in powerflow studies are considered representative of the transient period as well as the longer term. Hence some allowance is made for SVC controller voltage "droop" in B.C. Hydro's QV studies.

A 2% voltage droop value is used for planning studies. However, the appropriate value for a particular SVC will depend on many factors such as the size of the SVC relative to the system strength at the SVC location, whether the output of the SVC varies continuously or in discrete steps, the SVC's control system parameters and the dynamic response of the power system.

Critical Transmission Line Outages

The results of a wide range of voltage stability QV studies are tabulated in Table B1. In these "scan" studies, eleven different major transmission line outages were analyzed using nine different QV test buses. The values tabulated in Table B1 are the values of surplus reactive reserve at each of the nine QV test buses. The results of "scan" studies on four powerflow cases are provided in Table B1. The four cases, each modelling a different load/generation schedule combination for the 1994/95 system configuration, are:

Case p8702c0: This case has maximum Columbia generation and a B.C. Hydro I/S load of 8702 MW.

Case p9202c0: This case has maximum Columbia generation and a B.C. Hydro I/S load of 9202 MW.

Case p8702p0: This case has maximum Peace/Alcan generation and a B.C. Hydro I/S load of 8702 MW.

Case p9202p0: This case has maximum Peace/Alcan generation and a B.C. Hydro I/S load of 9202 MW.

These scan studies show that, for the base case system configuration, (a) the critical outage is an outage to circuit 5L82 (NIC-MDN) for conditions of maximum Columbia generation and (b) the

critical outage is an outage to circuit 5L42 (KLY-CKY#1) for conditions of maximum Peace generation.

The results of the scan studies for the case of maximum Columbia generation and a BCH V/S load level of 8700 MW are shown in Figure B2. Figure B2 demonstrates that the reactive reserves at the different test buses are lowest for a 5L82 (NIC-MDN) outage but the reserves for a 5L81 (NIC-ING) outage are not much higher as can be expected because these two lines are nearly equal in length and the receiving end terminal stations, Meridian and Ingledow, are not far apart.

Figure B2 also shows that, even under maximum Columbia generation conditions (ie reduced output from the Peace plants), the reactive power reserves are quite low for outages to circuit 5L42, the existing Kelly Lake to Cheekye 500 kV transmission line. This suggests that an additional transmission line between Kelly Lake and Cheekye substations may be an appropriate means of reinforcing the Interior to Lower Mainland transmission system.

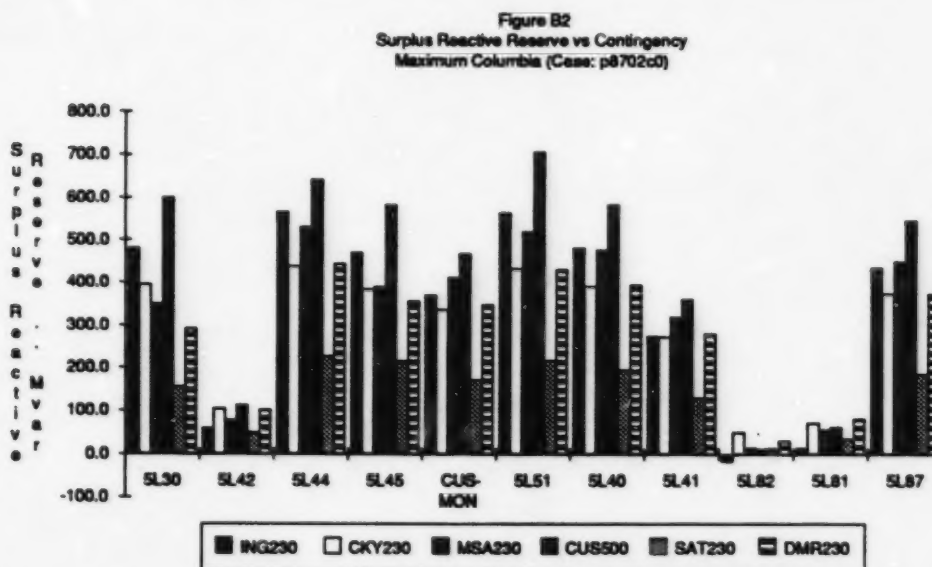
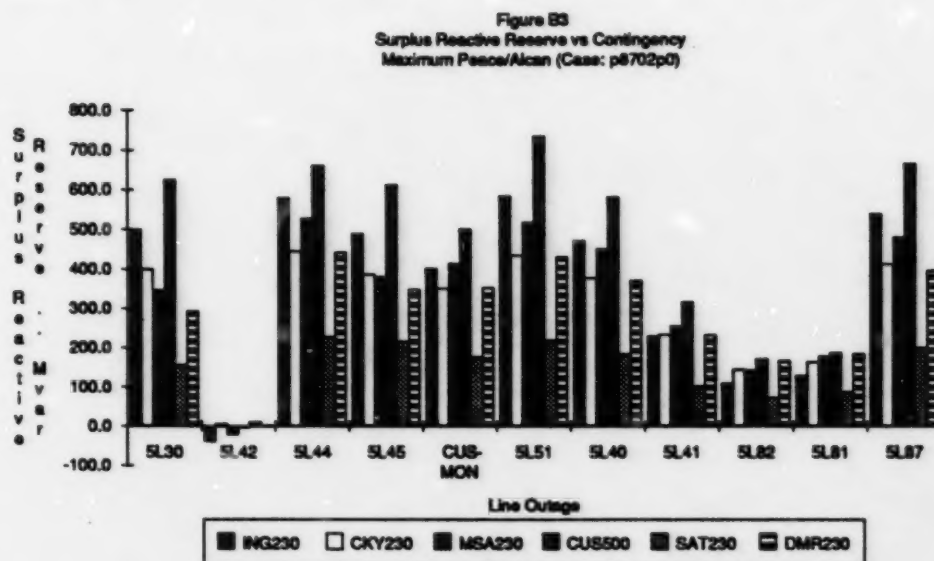


Figure B3 provides the results of similar "scan" studies performed on the Peace maximum base case. Figure B3 confirms that, for the 1994/95 system configuration, loss of circuit 5L42 (KLY-CKY#1) is the critical outage during conditions of maximum Peace/Alcan generation.



The sensitivity, to the severity of the major transmission system contingency, of the reactive power margin measured at a particular bus is an indication of how well that bus, when used as a QV test bus, measures the capability of the major transmission system. If a QV test bus produced the same margin regardless of the outage simulated, it would not provide any indication of the strength of the major transmission system. Buses that are electrically remote from the major transmission system would not be expected to be useful as QV test buses for the major transmission system.

Figure B4 shows the variation, with outage, of the reactive margins measured at 12 different QV test buses. Figure B4 plots the difference between the maximum reactive power reserve and minimum reactive power reserve for five different major transmission line outages (outages to circuits 5L41, 5L42, 5L81, 5L82 and 5L87). Buses which are very remote electrically from the major transmission system, such as the Dal Grauer 12 kV bus (DGR12), the Tsawwassen 25 kV bus (TSW25) and the Jordan River 25 kV bus (JOR25), show very little sensitivity to the severity of the major transmission system contingency.

Conversely, buses which are electrically very close to the major transmission system, such as the Custer 500 kV bus, and the Ingledow, Meridian and Malaspina 230 kV buses, are very sensitive to the severity of the major transmission system contingency.

QV curves readily provide information on the size of the dynamic reactive power source (eg SVC or S/C) required at the test bus to satisfy the dynamic reactive power reserve requirements. Figure B4 suggests that the Custer 500 kV bus and hence the electrically close Ingledow 500 kV bus would be good locations for QV test buses. However, using 500 kV buses as QV test buses would only provide an indication of voltage stability margins since installing an SVC on a 500 kV bus would probably not be economic compared to installing an SVC on a nearby 230 kV bus because of the large cost of 500 kV transformers. Therefore, the Ingledow, Malaspina and Dunsuir 230 kV buses were chosen as the three QV test buses for the studies of the Interior to Lower Mainland transmission system capability.

Ingledow was chosen rather than Meridian because Meridian is already very close to a large dynamic reactive power source, the Burrard synchronous condensers and, for security reasons,

it is desirable to distribute reactive sources throughout the load area rather than concentrating them in one location.

The Interior to Lower Mainland transmission system voltage stability limit, for a given system configuration, is estimated by interpolating or extrapolating from the results of two QV studies conducted at two different load levels. The result is a Lower Mainland plus Vancouver Island (LM/VI) load level (including losses in the transmission system southwest of KLY & NIC) at which reactive power margins, following the worst single contingency, are just adequate.

The two LM/VI load levels chosen for the studies undertaken for this report were 6109 MW and 6460 MW since these levels were expected to be near the system limits. These two LM/VI load levels, 6109 MW and 6460 MW, correspond to B.C. Hydro integrated system (I/S) load levels of 8702 MW and 9202 MW respectively.

Figure B5 shows the result of a QV study using the base case system (the proposed 1994/95 system configuration but without any LM or VI IPPs) during conditions of maximum Peace generation and 675 MW imported from Alcan. The QV curve is plotted for an outage to circuit 5L42 (KLY-CKY#1) at a LM/VI load level of 6109 MW (8702 MW BCH I/S load level). In this case, the reactive power margin was 47.0 Mvar less than required (ie the surplus reactive reserve was -47.0 MW).

The results of a similar study conducted at a LM/VI load level of 6460 MW (9202 MW BCH I/S load level) are provided in Figure B6. Figure B6 indicates that, for that case, the reactive power margin was less than the required amount by 211.8 Mvar.

Figure B7 is an example of extrapolating between the two study load levels to determine the LM/VI load limit. Figure B7 plots the results of the two QV studies described above (Figures B5 & B6).

Extrapolating from the two QV studies, results in a LM/VI load limit of 6010 MW, as shown in Figure B7. This means that, for the base case system configuration, the Interior to Lower Mainland transmission system voltage stability limit is reached when the LM/VI load reaches 6010 MW. The corresponding total BCH I/S load would be about 8560 MW.

APPENDIX C

STUDY RESULTS

APPENDIX C: STUDY RESULTS

Details of the results of the studies undertaken for this investigation of the capability of the Interior to Lower Mainland transmission system are tabulated in Table C1. The details of each case are provided below:

Case A (Base Case): The base system, to which each study is compared is the 1994/95 stage of system development shown in Figure 3 with the exception that this base case has no LM/VI IPPs.

Case B (122 MW LM/VI IPPs): The addition of 122 MW of dependable LM/VI IPP generating capacity was represented as a 122 MW output from the Burrard synchronous condensers.

Case C (Additional Columbia Generation): Case C, models the addition of a fifth 461 MW generator at the Revelstoke generating plant. This fifth unit is identical to the other existing four generators at Revelstoke. The output from the Peace generation is reduced by about 460 MW.

Case D (Additional Peace Generation): Case D models the addition of half of the Site C plant (450 MW) to the system. The data used for this plant is very similar to the Peace Canyon plant data. The 450 MW Site C plant was connected to the rest of the system via a single 500 kV transmission line to the existing Peace Canyon generating station. The output from the Columbia generation is reduced by about 450 MW.

Case E (Importing 450 MW from the USA): Importing 450 MW from the USA was modelled by changing the 120 MW export to the USA in the base case to a 330 MW import from the USA. The outputs of all of the generators in the USA (from Montana to southern California) were scaled up by 450 MW. In the maximum Columbia generation cases, the Peace generation was reduced by about 450 MW and, conversely, in the maximum Peace generation cases, the Columbia generation was reduced by about 450 MW.

Case F (LM-VI Generation Level): In this case the outputs of all of the generating plants in the Lower Mainland, Vancouver Island and Bridge River regions were scaled down, in proportion to their initial output, by a total of 200 MW.

Case G (Burrard Generation): Case G modelled the two non-synchronous condenser units at the Burrard Thermal generating station operating at 150 MW each. They were modelled without line drop compensation (LDC).

Case H (Rescheduling USA Generation): Case H modelled shutting down the 1280 MW Centralia plant near Tacoma in Washington state and replacing this lost generation by increasing the outputs of all generating plants in the Pacific Northwestern USA system west of Seattle/Portland by 4.9%.

Case I (Operating BUT G5 & G6 in S/C Mode): This case is identical to Case G above except that, in this case, the two Burrard units are operated at zero real power output compared to 300 MW output for Case G.

Case J (Fraser Valley 300 MW Generating Plant): The data used for the generation addition in Case J is identical to that of Case G (running Burrard G5 & G6 at 300 MW). The only difference being that, in Case J, the 300 MW generating plant was connected to the 230 kV bus in the Atchelitz substation near Sardis in the Fraser Valley whereas, in Case G, the same 300 MW plant was connected to the 230 kV bus in the Burrard station near Port Moody. Like Case G, no line drop compensation (LDC) was modelled on the Atchelitz generator.

TABLES

Table 1: B.C. Hydro Integrated System Load Forecast

Table 2: Resource Plans

Table B1: Powerflow QV "Scan" Study Results

Table C1: Study Details

Table 1
B.C. Hydro Total Generation Requirement
During Winter Peak Load Hour
Based on Fall 1990 Forecast
(MW)

Winter Generation for B.C. Hydro Load (Last Year's Forecast) Extrapolated Load *	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11
Demand Side Management (DSM)	7870	8160	8420	8680	8900	9170	9410	9610	9850	10090	10380	10630	10890	11160	11420	11680	11920	12170	12410	12620	
Subtracting DSM	7883	8146	8342	8614	8867	9326	9566	9766	10006	10246	10536	10786	11046	11316	11576	11836	12076	12326	12566	12776	12990
Electric Plus (E+)	7828	8001	8109	8293	8572	8869	-504	-554	-602	-643	-672	-691	-704	-714	-725	-739	-754	-770	-785	-799	-813
Including DSM & E+ (less note)	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
Generation for Export to WKPL ** SCL Firm Contract	7943	8116	8224	8408	8687	8984	9177	9327	9519	9718	9979	10210	10457	10717	10988	11212	11437	11671	11896	12092	12291
Total Generation needed Including WKPL and SCL	8217	8411	8395	8582	8916	9226	9434	9597	9809	10007	10282	10523	10783	11054	11318	11575	11814	12061	12301	12513	12727

Note: This is the "probable" peak load for the BC Hydro Integrated System. The average annual growth rate is 2.2 %

* After 1995 Annual Growth same as Last Year's Forecast
** Diversity Factor 0.95 and Loss Factor 1.07 for WKPL loads

Table 1

TABLE 2

RESOURCE DEVELOPMENT SUMMARY
SCHEDULED & POSSIBLE NEW RESOURCES

YEAR	RESOURCE ADDITION	REGIONAL LOCATION	RATED CAPACITY MW	CUMULATIVE CAPACITY ADDITIONS BY REGION				YEARLY CAPACITY ADDITIONS	
				LM & VI MW	PEACE MW	COLUMBIA MW	OVERALL TOTAL MW	YEAR	ADDED MW
1983	McArthur (Taylor)	Peace	106	0	106	0	106	1981/82	None
1983	Mt. Energy (Williams Lake)	Peace	95	0	160	0	160		
1993	Isaquan (Squamish)	LM	50	50	160	0	210	1993	210
1994	LM & VI Self Generation	LM & VI	90	140	160	0	300		
1994	Peace Self Generation	Peace	118	140	275	0	415		
1994	Columbia Self Generation	Columbia	40	140	275	40	455	1994	245
1995	Reseno Completion Project	Peace	520	140	795	40	975	1995	520
1996	LM & VI Self Generation	LM & VI	60	200	795	40	1035		
1996	Peace Self Generation	Peace	80	200	875	40	1115	1996 1997	140 None
1998	Downstream Benefits (LM)) Downstream Benefits (SI)) 1100	LM	50	250	875	40	1165		
1998	Downstream Benefits (SI))	Columbia	50	250	875	90	1215	1998	215
1998	Peace Self-Generation	Peace	100	250	975	90	1315		
1998	Columbia Self-Generation	Columbia	15	250	975	105	1330		
1999	Keenleyside	Columbia	240	250	975	345	1570		
1999	Downstream Benefits (LM)) Downstream Benefits (SI)) 1500	LM	250	500	975	345	1820		
1999	Downstream Benefits (SI))	Columbia	250	500	975	595	2070	1999 2000/01 2002	740 None 380
2002	Manita Expansion	Columbia	380	500	975	975	2450		
2003	Site C	Peace	900	500	1875	975	3350		
2003	Seven Mile #4	Columbia	200	500	1875	1175	3650		
2003	Downstream Benefits (LM)) Downstream Benefits (SI)) 1600	LM	250	750	1875	1175	3600		
2003	Downstream Benefits (SI))	Columbia	250	750	1875	1425	4050	2003 2004 2005	1600 None 160
2006	Brilliant Expansion	Columbia	150	750	1875	1575	4200		
2006	Duncan	Columbia	25	750	1875	1500	4225		
2006	Lower Canyon	Peace	350	750	2225	1600	4585	2006	385
2007	Elmo	LM	340	1090	2235	1600	4925	2007 2008 2009	340 None 275
2008	Murphy Creek	Columbia	275	1090	2235	1875	5200	2010/12	None
2013	Border	Columbia	275	1090	2235	2150	5475	2013	275

TABLE B1
Powerflow QV "Scan" Study Results

CASE P8702CO

QV Test Bus		5L30	5L42	5L44	5L45	CUS-MON	5L51	5L40	5L41	5L82	5L81	5L87
1201	ING230	479.9	59.5	565.6	469.1	369.3	563.3	480.1	273.4	-17.9	14.2	434.5
201	CKY230	393.9	103.5	438.7	383.8	336.0	431.9	391.1	272.9	49.3	70.8	372.8
202	MSA230	349.6	77.8	529.9	389.8	411.3	519.0	476.2	318.3	14.6	55.8	449.0
7798	CUS500	600.2	112.6	642.3	561.7	466.0	706.4	582.8	359.1	11.4	61.5	544.7
2202	SAT230	155.9	49.9	227.2	214.9	171.7	217.1	195.0	130.2	12.8	36.5	184.8
2216	DMR230	291.0	100.6	443.4	354.7	347.1	429.4	393.4	279.4	30.5	80.8	372.1
1244	CBN230	503.5	92.5	569.3	510.3	410.6	571.0	522.5	287.2	6.6	38.5	475.2
1215	ARN230	440.5	51.0	518.9	436.6	339.1	512.6	442.7	247.9	-27.4	7.2	398.2
203	MDN230	526.1	77.6	629.0	499.7	410.8	608.2	521.6	312.9	-12.9	29.2	479.8

CASE P9202CO

QV Test Bus		5L30	5L42	5L44	5L45	CUS-MON	5L51	5L40	5L41	5L82	5L81	5L87
1201	ING230	362.3	-149.5	444.3	338.3	256.1	446.3	351.1	117.0	-159.5	-118.2	348.5
201	CKY230	321.0	-121.9	373.0	308.1	257.8	365.2	309.0	155.1	-129.3	-81.0	311.7
202	MSA230	290.5	-125.8	482.1	346.4	319.2	462.4	394.3	181.7	-136.3	-90.3	396.4
7798	CUS500	483.7	-132.8	545.3	450.3	351.4	608.0	457.7	191.4	-138.2	-97.2	459.1
2202	SAT230	124.7	-70.1	197.9	192.0	137.3	188.4	157.4	72.2	-91.7	-35.6	159.1
2216	DMR230	242.8	-113.1	395.2	318.9	286.1	377.9	327.9	180.8	-121.9	-74.2	327.1
1244	CBN230	396.4	-136.7	460.5	384.9	298.3	471.4	406.9	143.3	-140.9	-104.0	391.9
1215	ARN230	331.2	-155.5	407.5	317.2	235.1	412.0	325.1	104.9	-158.2	-122.4	319.0
203	MDN230	399.2	-145.4	512.8	362.0	294.9	490.1	391.6	148.6	-148.1	-105.4	387.0

CASE P8702PO

QV Test Bus		5L30	5L42	5L44	5L45	CUS-MON	5L51	5L40	5L41	5L82	5L81	5L87
1201	ING230	498.3	-40.5	579.8	488.6	400.6	583.7	471.5	229.2	108.9	127.9	537.8
201	CKY230	399.7	4.9	444.2	385.9	350.6	433.8	376.8	234.2	145.2	163.1	412.3
202	MSA230	346.0	-22.9	528.1	380.0	413.3	518.5	450.9	256.3	143.5	178.6	479.5
7798	CUS500	625.2	-5.0	660.7	612.0	500.8	734.9	581.6	315.3	171.2	187.3	664.4
2202	SAT230	156.6	10.3	227.8	216.2	176.3	218.4	183.4	102.3	72.8	87.0	199.4
2216	DMR230	292.8	1.0	441.3	348.2	352.8	429.8	369.7	233.0	166.6	184.0	395.1
1244	CBN230	512.4	-26.4	573.9	523.3	432.2	582.7	484.4	248.0	136.4	156.3	539.9
1215	ARN230	456.9	-47.0	530.7	454.2	368.7	531.5	432.3	209.5	97.1	113.1	490.5
203	MDN230	546.5	-41.3	652.7	523.1	446.3	633.9	514.9	265.1	129.1	154.9	568.2

CASE P9202PO

QV Test Bus		5L30	5L42	5L44	5L45	CUS-MON	5L51	5L40	5L41	5L82	5L81	5L87
1201	ING230	369.3	-205.8	449.0	346.0	271.5	455.0	344.7	92.0	-83.2	-56.6	403.9
201	CKY230	323.9	-197.3	376.4	306.4	266.2	367.8	303.5	130.1	-41.3	6.6	339.7
202	MSA230	297.0	-199.4	478.9	340.3	325.5	456.1	389.6	139.9	-40.1	-10.6	420.3
7798	CUS500	492.0	-204.8	549.8	461.4	367.4	615.8	454.1	159.1	-53.5	-17.8	528.1
2202	SAT230	125.8	-188.3	197.6	191.8	140.4	188.4	149.6	52.7	60.6	5.7	167.7
2216	DMR230	244.5	-192.7	393.4	313.6	290.3	377.1	312.2	151.7	-29.7	6.3	341.1
1244	CBN230	395.4	-206.1	467.6	386.2	303.2	471.6	380.1	113.0	-59.8	-34.7	428.4
1215	ARN230	337.6	-211.3	412.8	321.4	250.4	420.9	319.2	78.2	-84.5	-60.1	369.1
203	MDN230	408.3	-204.9	520.8	375.1	308.4	497.9	383.6	114.0	-65.8	-43.1	440.8

Table C1

Interior to Lower Mainland Transmission Capability Sensitivity Studies
70.20% - LM/VI Load as a function of BCH Load

Case:	A	B	C	D	E	F	G	H	I	J
Peace Limits:										
QVbus1	8586.1	8704.3	8624.2	8385.4	8754.6	8416.8	9203.0	8409.9	8885.6	9010.0
QVbus2	8642.3	8753.5	8680.7	8490.4	8839.7	8489.2	9252.5	8535.5	8922.7	9060.4
QVbus3	8704.8	8833.2	8728.5	8558.5	8922.8	8565.2	9343.5	8617.5	8909.8	9097.6
Columbia Limits:										
QVbus1	8644.5	8783.8	8464.9	8653.6	8812.6	8456.1	9324.3	8448.0	8981.5	9152.6
QVbus2	8753.9	8924.3	8553.0	8768.5	9001.0	8549.9	9505.7	8549.5	9073.7	9260.7
QVbus3	8816.7	8999.6	8615.7	8825.2	9073.6	8608.9	9620.6	8624.5	9088.7	9341.5
System Limits:										
QVbus1	8586.1	8704.3	8464.9	8385.4	8754.6	8416.8	9203.0	8409.9	8885.6	9010.0
QVbus2	8642.3	8753.5	8553.0	8490.4	8839.7	8489.2	9252.5	8535.5	8922.7	9060.4
QVbus3	8704.8	8833.2	8615.7	8558.5	8922.8	8565.2	9343.5	8617.5	8909.8	9097.6
Overall Limits:										
Peace	8586.1	8704.3	8624.2	8385.4	8754.6	8416.8	9203.0	8409.9	8885.6	9010.0
Columbia	8844.5	8783.8	8464.9	8653.6	8812.6	8456.1	9324.3	8448.0	8981.5	9152.6
Limit Increase:										
Peace	0.0	118.2	38.1	-200.7	168.5	-169.3	616.9	-176.2	299.5	423.9
Columbia	0.0	139.3	-179.6	9.1	168.1	-188.4	679.8	-196.5	337.0	508.1
Change in LM/VI Load Limit (MW):										
Peace	0.0	83.0	26.7	-140.9	118.3	-118.8	433.1	-123.7	210.2	297.6
Columbia	0.0	97.8	-126.1	6.4	118.0	-132.3	477.2	-137.9	236.6	356.7

Case A: Base Case system (94/95 System Configuration of 20 Nov 90 Plan without LM IPPs).

Case B: LM 122 MW IPP added (BUT S/C O/P changed to 122 MW; ipp122a.idv).

Case C: 461 MW generator added at Revelstoke (rev5a.idv).

Case D: 450 MW added at Site C (sic450a.idv).

Case E: 450 MW imported from the USA.

Case F: LM, VI BR generation scaled down 200 MW to 938 MW (lmvi938.idv).

Case G: BUT G5 & G6 operated at 150 MW each without LDC (but300.idv).

Case H: 1280 MW Centralia (Tacoma) plant shut down (usagen.idv).

Case I: BUT G5 & G6 operated as S/Cs without LDC (but0.idv).

Case J: 300 MW IPP added at ALZ 230 kV bus without LDC (alz300.idv).

FIGURES

Figure 1: B.C. Hydro Major Transmission System

Figure 2: Interior to Lower Mainland Transmission Network

Figure 3: System Transmission Plan (1991/92-2013/14)

Figure 4: LM & VI Total Load

Figure 5: LM/VI Load Limit Sensitivity

Figure A1: Powerflow Base Case One-Line Diagram

Figure B1: Voltage Stability Criteria - Typical QV Curve

Figure B2: Maximum Columbia Generation QV "Scan" Studies

Figure B3: Maximum Peace Generation QV "Scan" Studies

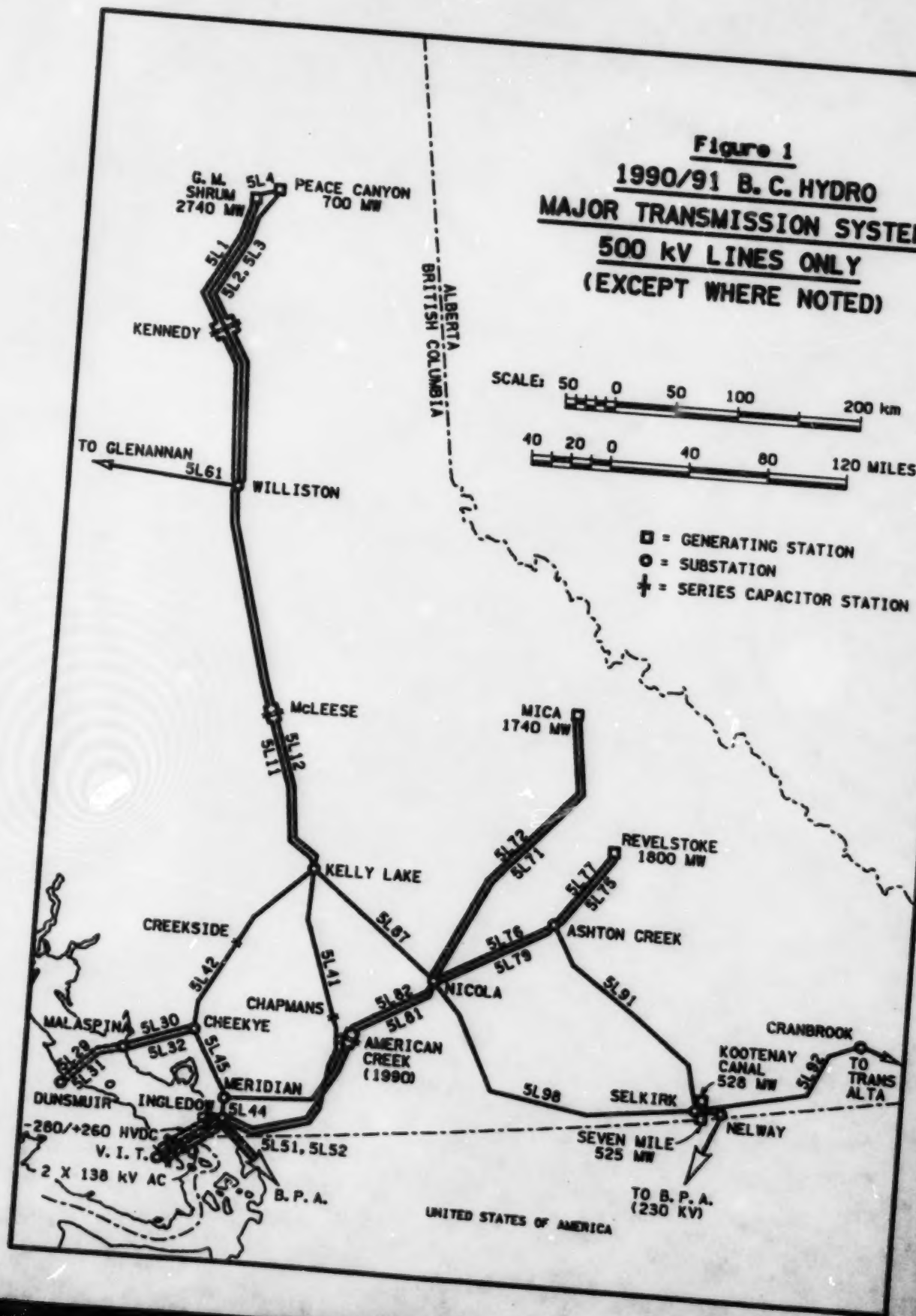
Figure B4: QV Bus Sensitivity to Line Outage

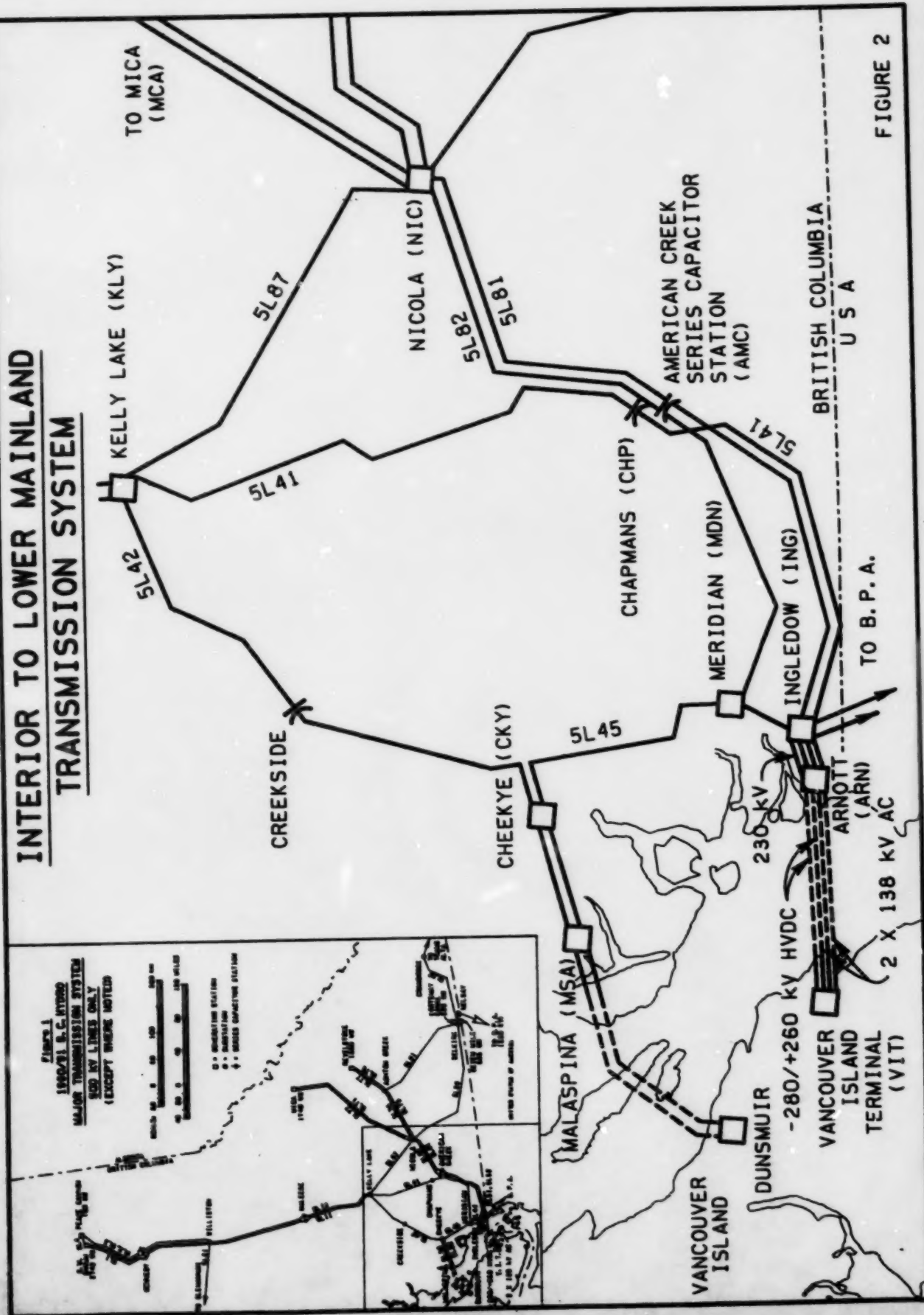
Figure B5: QV Study of 5L42 Outage (8702 MW BCH Load)

Figure B6: QV Study of 5L42 Outage (9202 MW BCH Load)

Figure B7: Surplus Reactive Reserve vs LM/VI Load

Figure 1
1990/91 B. C. HYDRO
MAJOR TRANSMISSION SYSTEM
500 KV LINES ONLY
(EXCEPT WHERE NOTED)



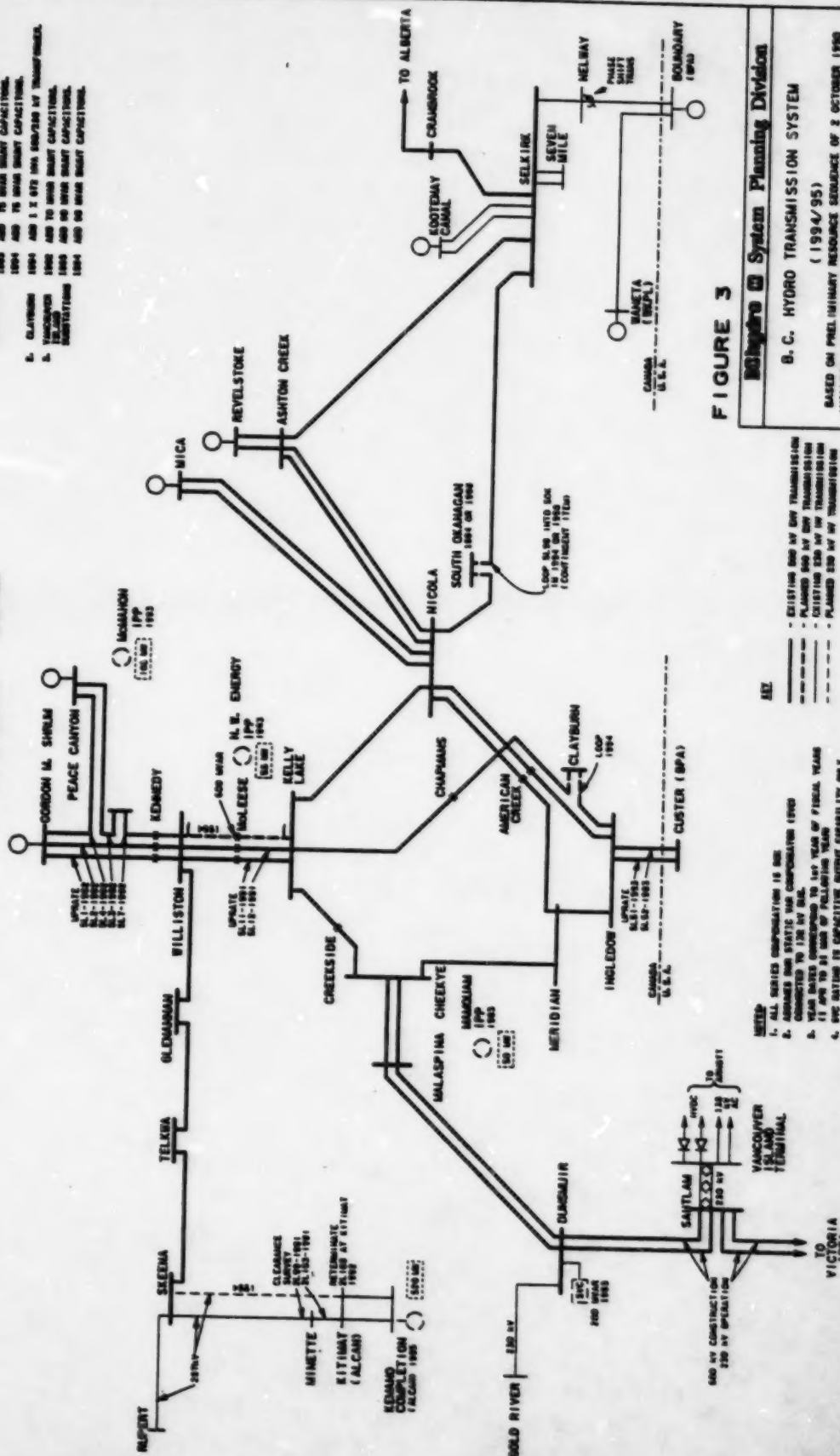


INDEPENDENT POWER PRODUCERS (IPPs) FOR DOMESTIC MARKET

- 1) BRITISH COLUMBIA
- 2) B.C. ENERGY (BRILLIANT LAKE)
- 3) B.C. ENERGY (CHAMBERS)
- 4) B.C. ENERGY (CHAMBERS)
- 5) B.C. ENERGY (CHAMBERS)
- 6) B.C. ENERGY (CHAMBERS)

MAJOR STATION REQUIREMENTS

- A. LAKES AND DAMS
1991 AND 1992 500 MW SHUNT CAPACITOR
1993 AND 1994 400 MW SHUNT CAPACITOR
1995 AND 1996 300 MW SHUNT CAPACITOR
1997 AND 1998 200 MW SHUNT CAPACITOR
1999 AND 2000 100 MW SHUNT CAPACITOR
- B. CLAYTON
1991 AND 1992 100 MW SHUNT CAPACITOR
1993 AND 1994 100 MW SHUNT CAPACITOR
1995 AND 1996 100 MW SHUNT CAPACITOR
1997 AND 1998 100 MW SHUNT CAPACITOR
1999 AND 2000 100 MW SHUNT CAPACITOR
- C. TACOMA
1991 AND 1992 100 MW SHUNT CAPACITOR
1993 AND 1994 100 MW SHUNT CAPACITOR
1995 AND 1996 100 MW SHUNT CAPACITOR
1997 AND 1998 100 MW SHUNT CAPACITOR
1999 AND 2000 100 MW SHUNT CAPACITOR



- LEGEND
1. ALL SERIES CAPACITORS 10 MW
 2. ADAPTED AND STATIC VAR COMPENSATOR (SVC)
 3. YEAR DATES CORRESPOND TO 100 YEAR OF FISCAL YEAR
 4. SVC RATING IS CAPACITIVE OUTPUT CAPABILITY ONLY.

- KEY
- EXISTING 230 KV DRY TRANSMISSION
 - PLANNED 230 KV DRY TRANSMISSION
 - PLANNED 230 KV WET TRANSMISSION
 - PLANNED 230 KV WET TRANSMISSION

FIGURE 3

B.C. HYDRO TRANSMISSION SYSTEM
(1994/95)

BASED ON PRELIMINARY RESOURCE SEQUENCE OF 2 OCTOBER 1990

INCLUDES IPPS FOR DOMESTIC LOADS, EXCLUDES IPPS FOR EXPORT

DATE: 10/10/91

P. 10.10 - 10/10/91

10/10/91

10/10/91

10/10/91

10/10/91

10/10/91

10/10/91

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Figure 4
LM/VI Total Load Forecast

September 1990 Forecast

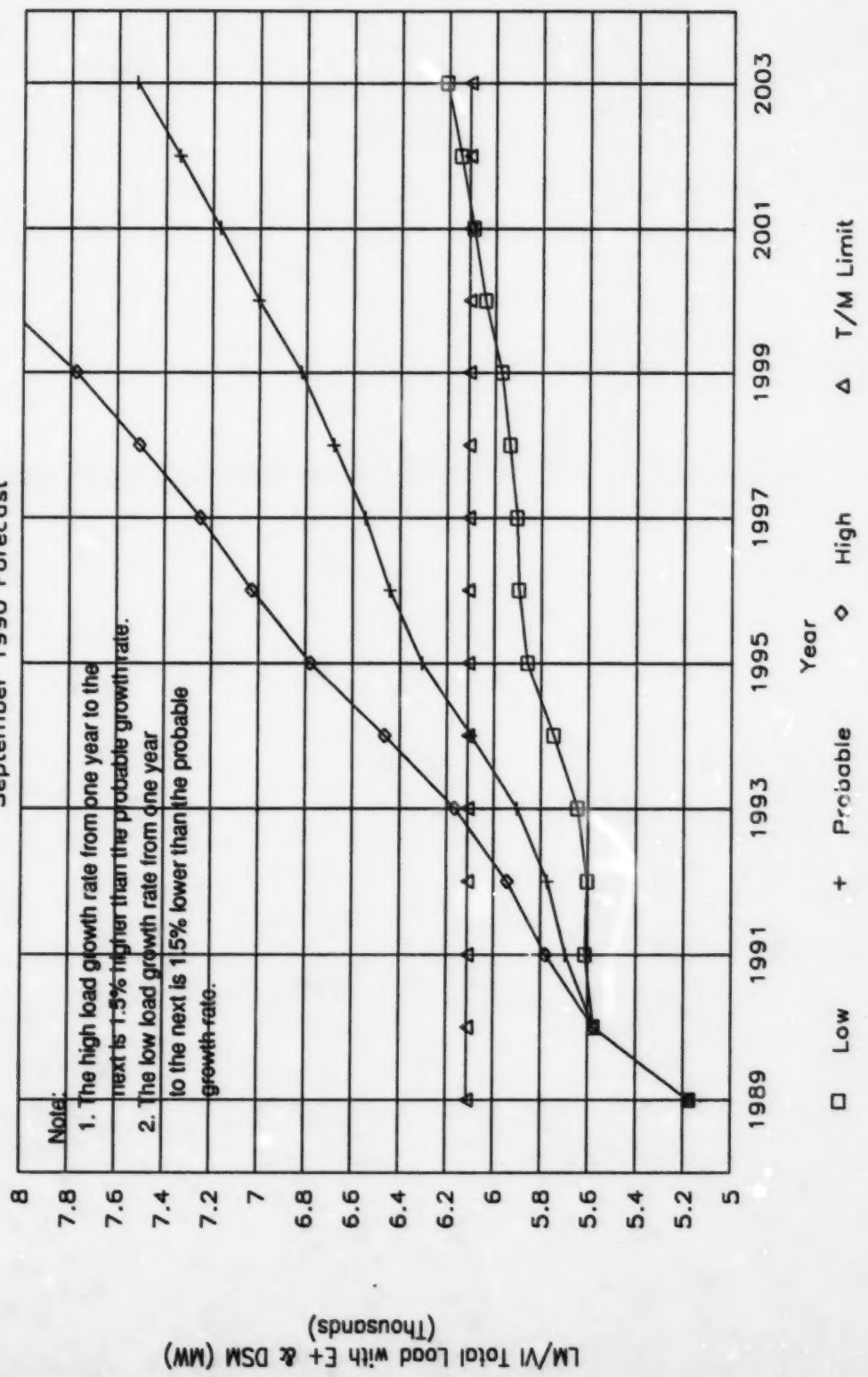
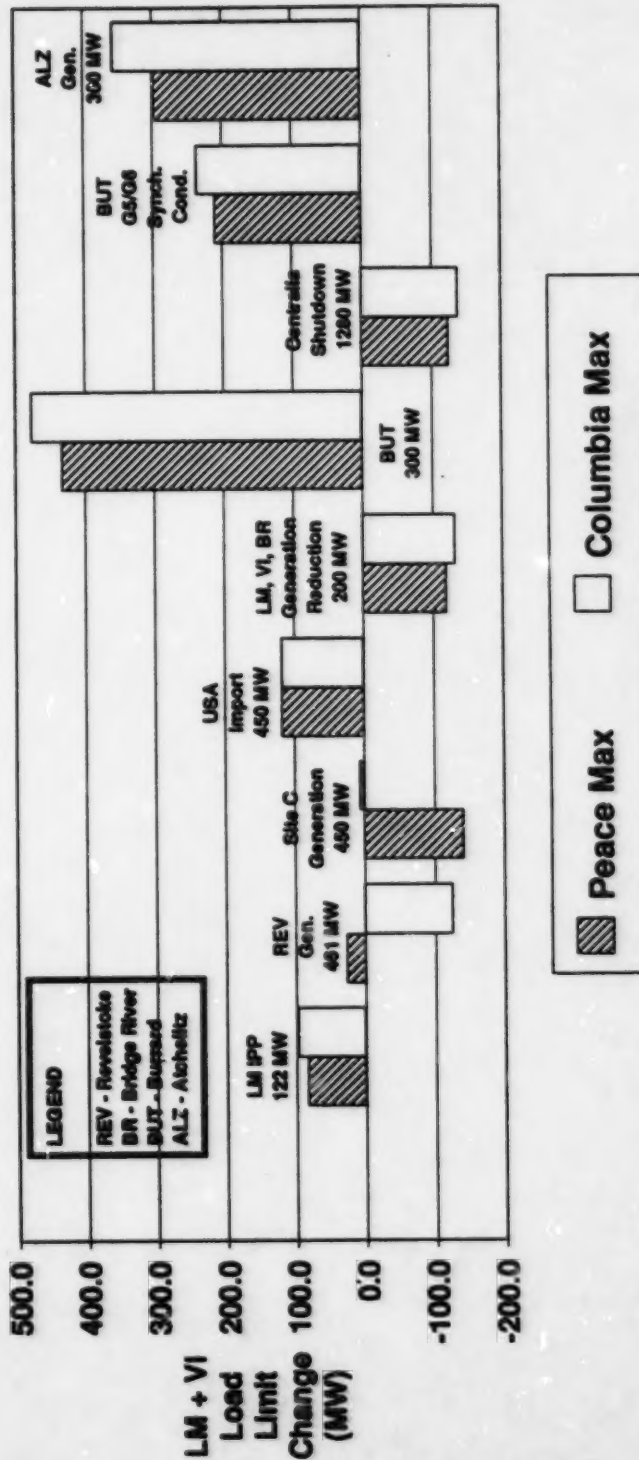


Figure 5
LM + VI Load Limit Change
Sensitivity to Local & Remote Generation Changes



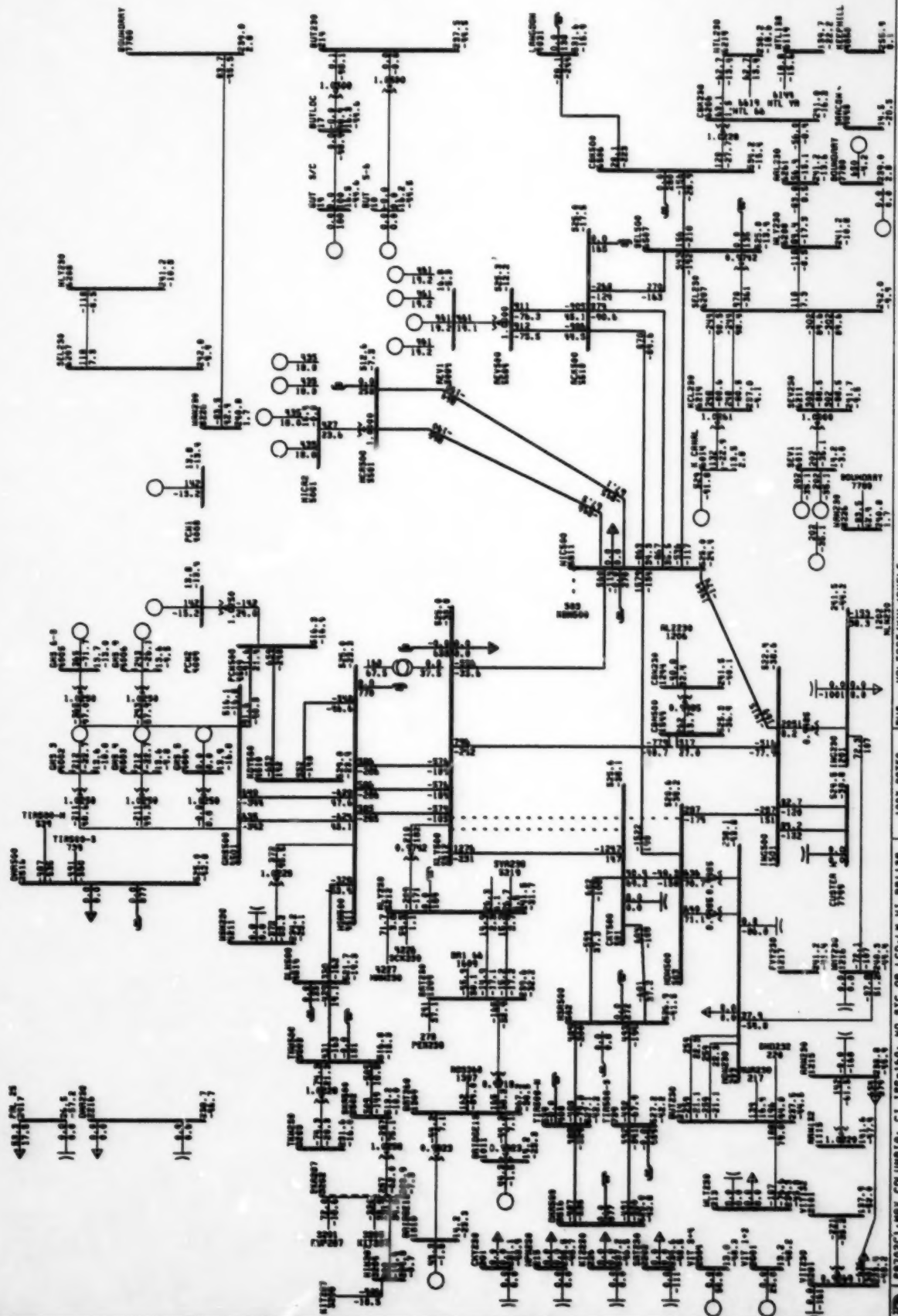
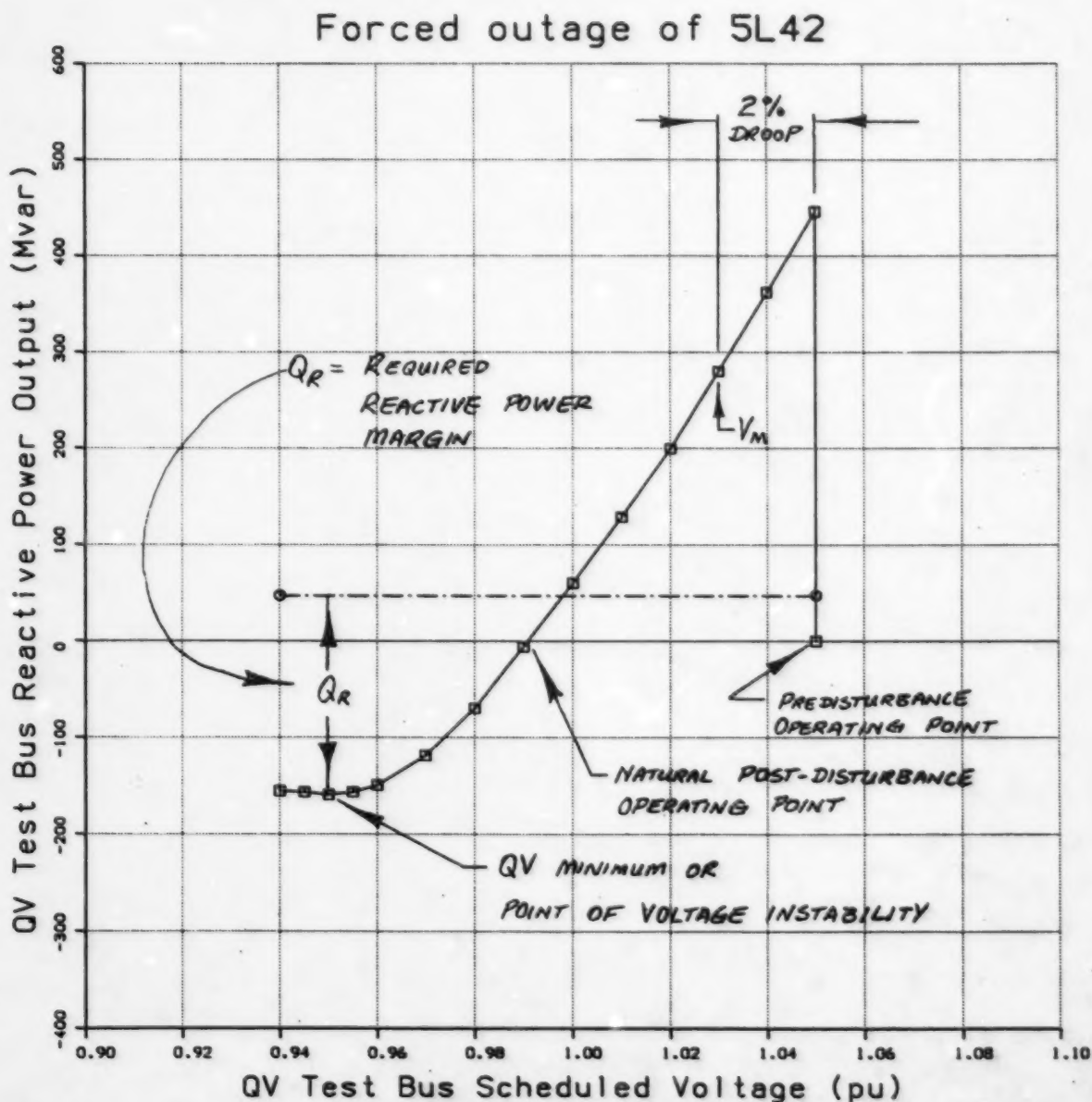


FIGURE A1

100% RATED 0.350 MJ L100.0Y V: 230 . 000	BUS - VOLTAGE (KV) / ANGLE BRANCH - MW/MVAR EQUIPMENT - MW/MVAR
--	---

P8702C1; MAX COLUMBIA; C1 IPP-150; NO SIC OR LCD; LN.VI.BA1139
REV1; EXPORTS; WKP--228, ALCAN-675, TAUC-0, BPA--120
PGH/INTLM2/ADR158 FBI, DEC 14 1990 14:52

FIGURE B1
B.C. Hydro
Voltage Stability Criteria



Post outage unsupported voltage: 0.991 p.u.
 Bottom of curve: 0.950 p.u., -158.9 Mvar
 Reactive reserve minus margin: -47.0 Mvar

Figure B2

Surplus Reactive Reserve vs Contingency

Maximum Columbia (Case: p8702c0)

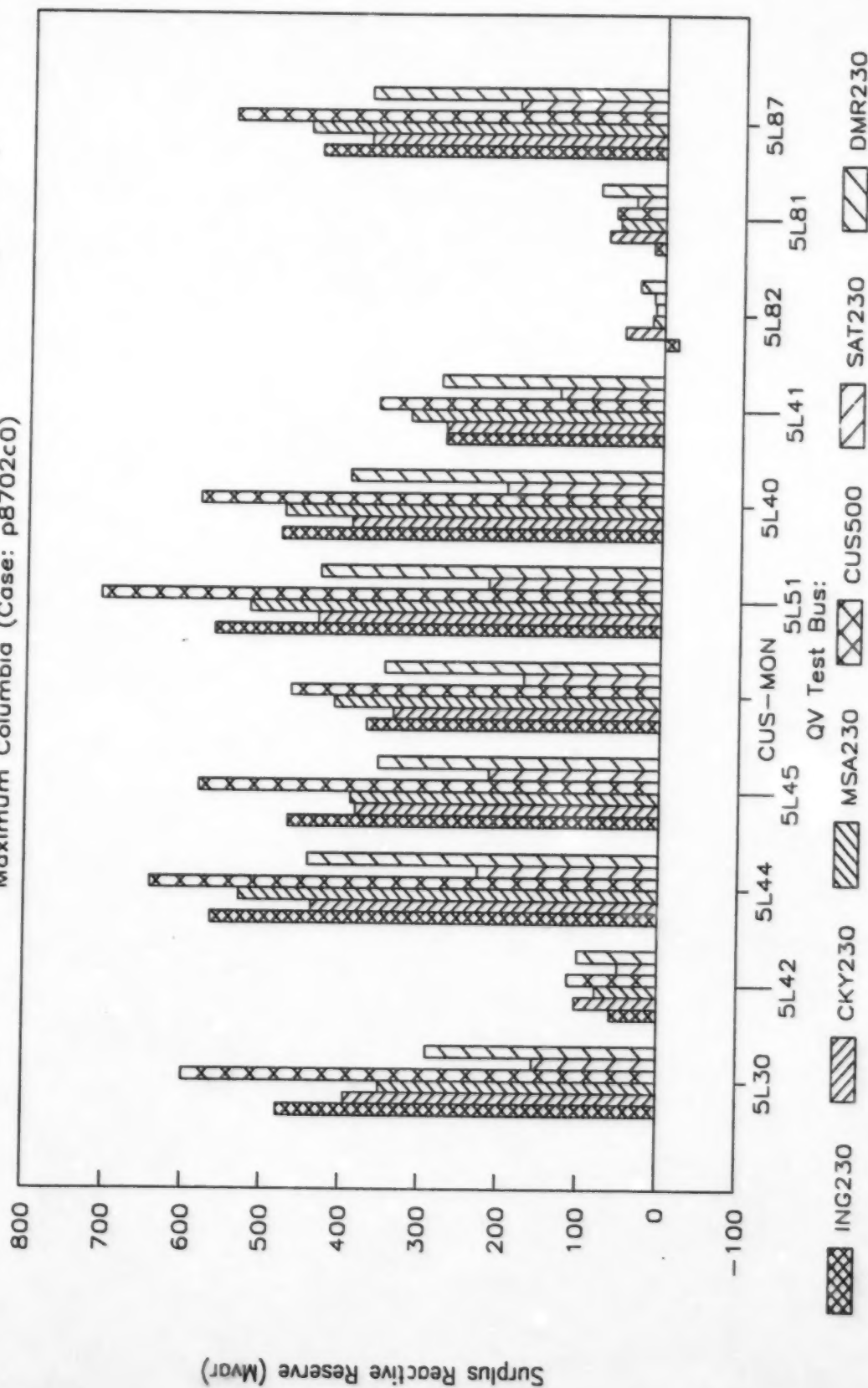


Figure B3

Surplus Reactive Reserve vs Contingency

Maximum Peace/Alcan (Case: p8702p0)

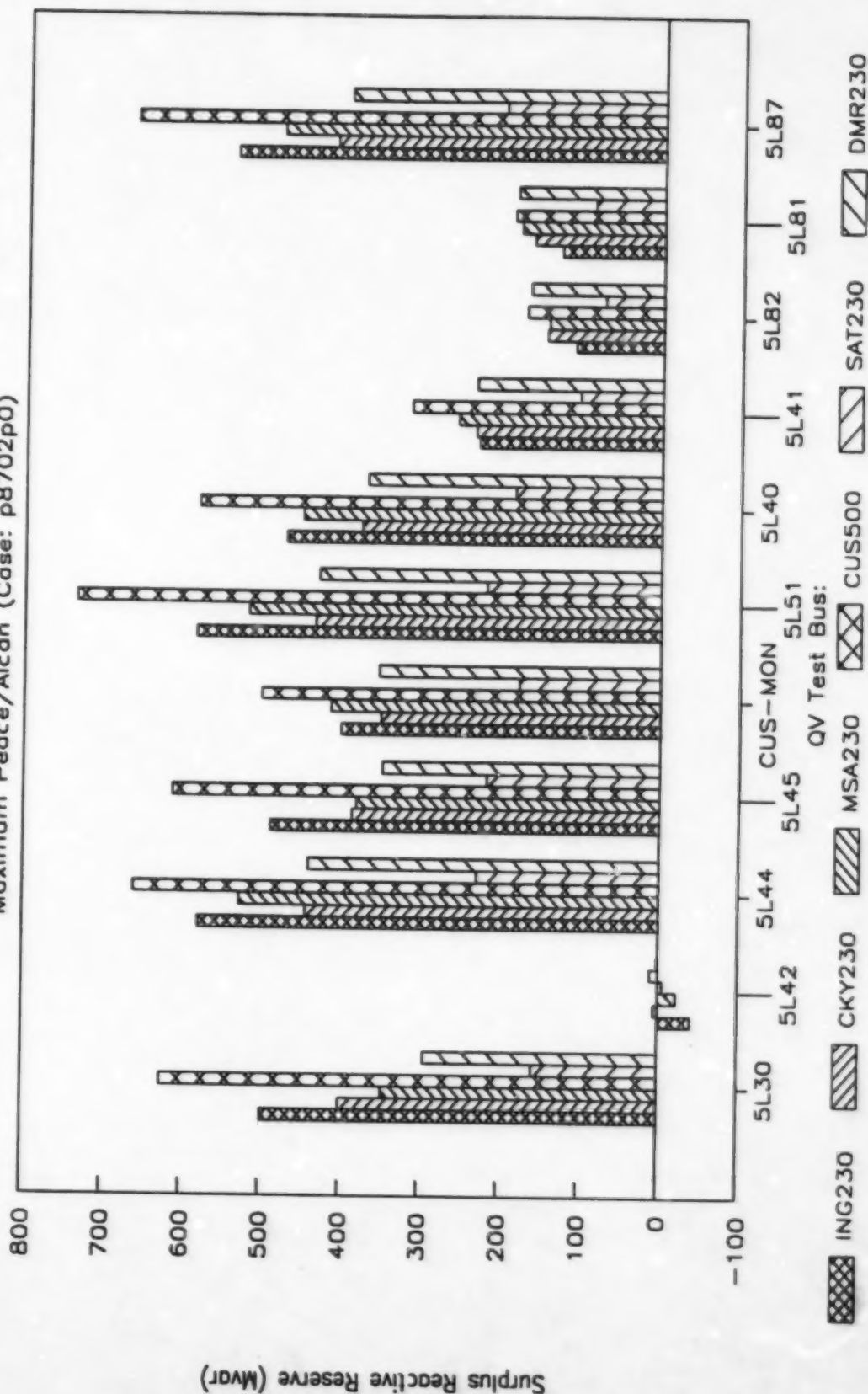
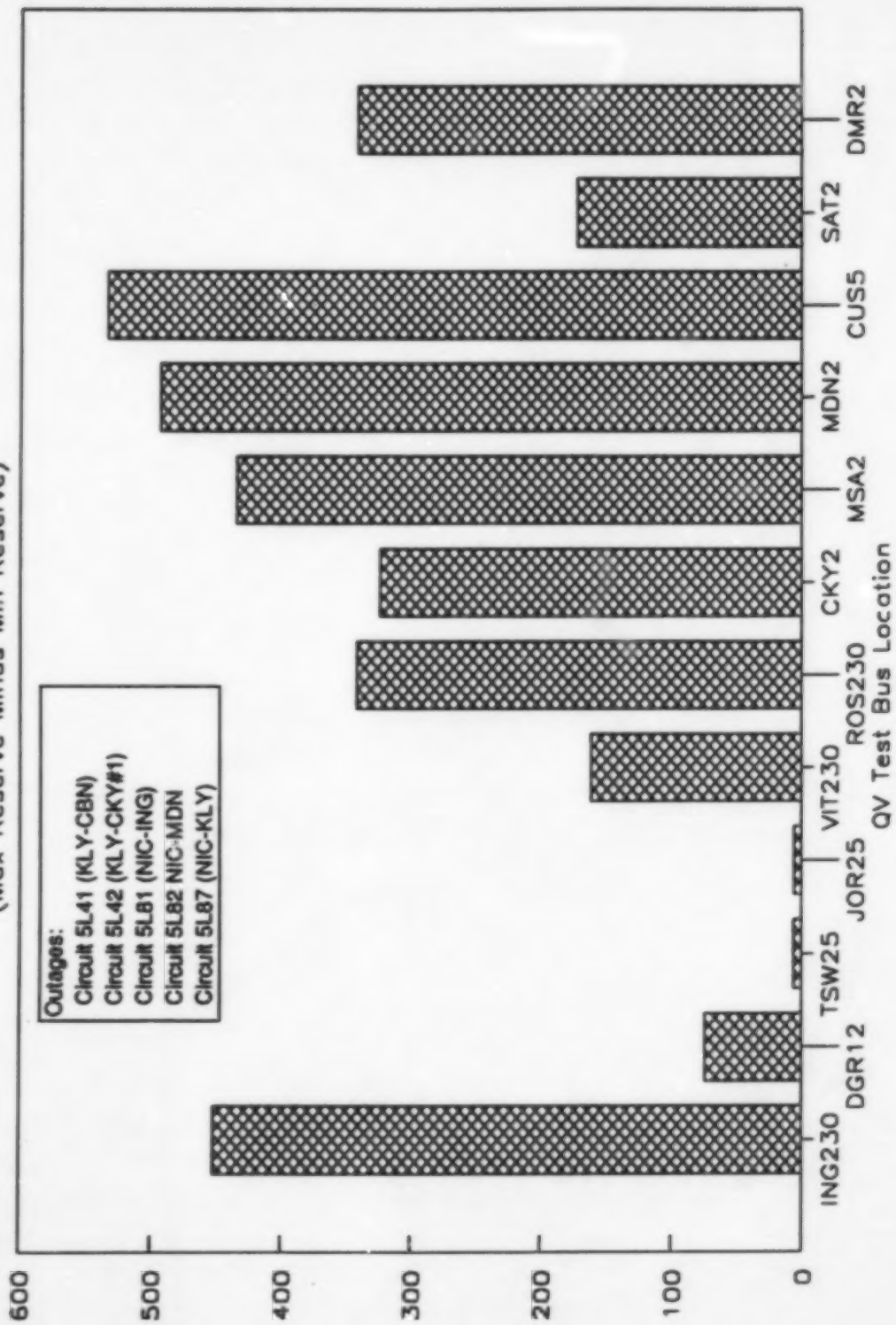


Figure B4

Sensitivity of QV Bus to Line Outage

(Max Reserve Minus Min Reserve)

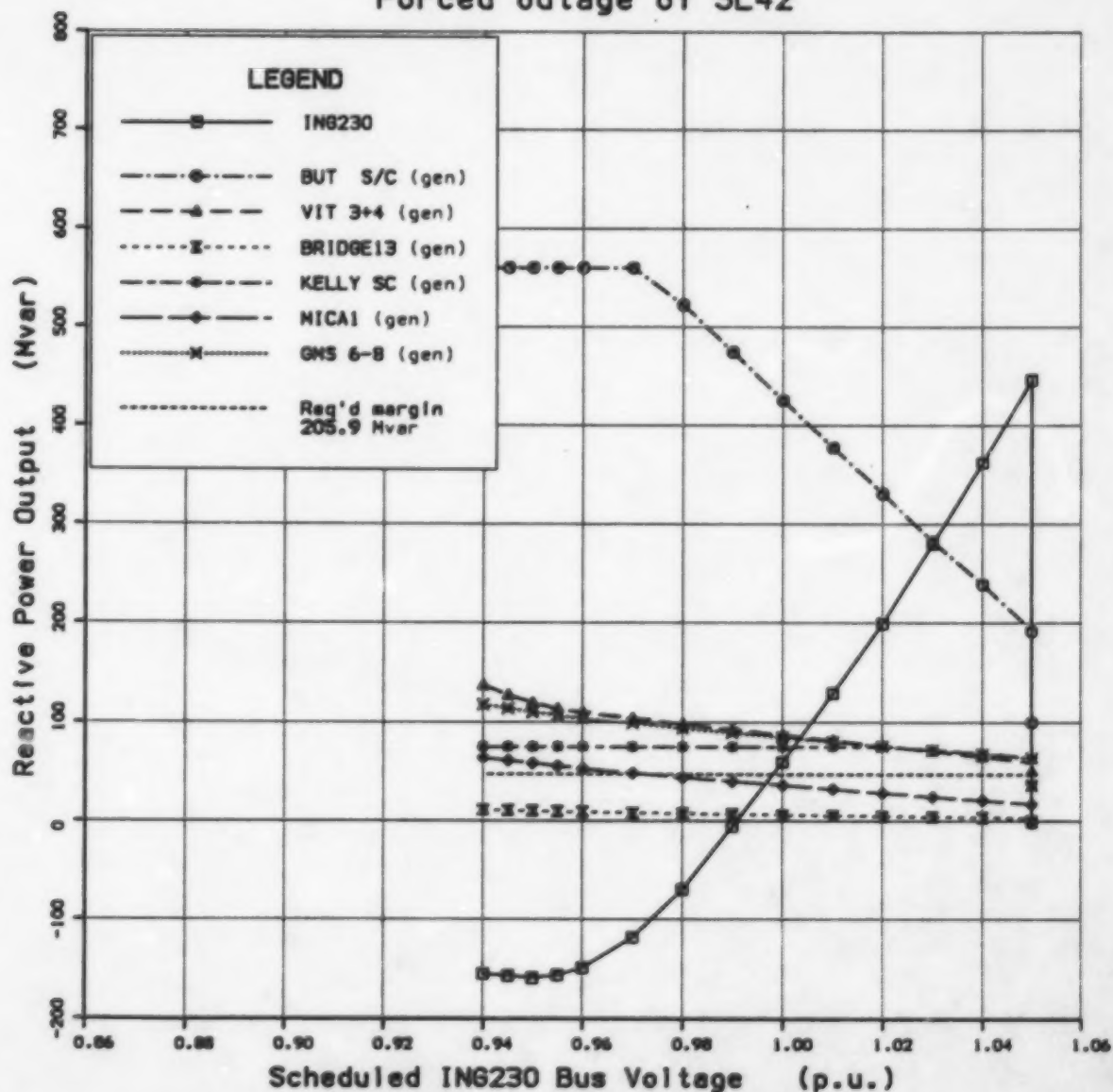


Max Reserve Minus Min Reserve (Mw)

FIGURE B5 Voltage Stability Study

P8702P;MAX PEACE,VI=1138;IPP CI=160 ;NO SITEC OR LCD;
REV1: EXPORTS: WKP=-228,ALCAN=675,TAUC=0,BPA=-120

Forced outage of 5L42

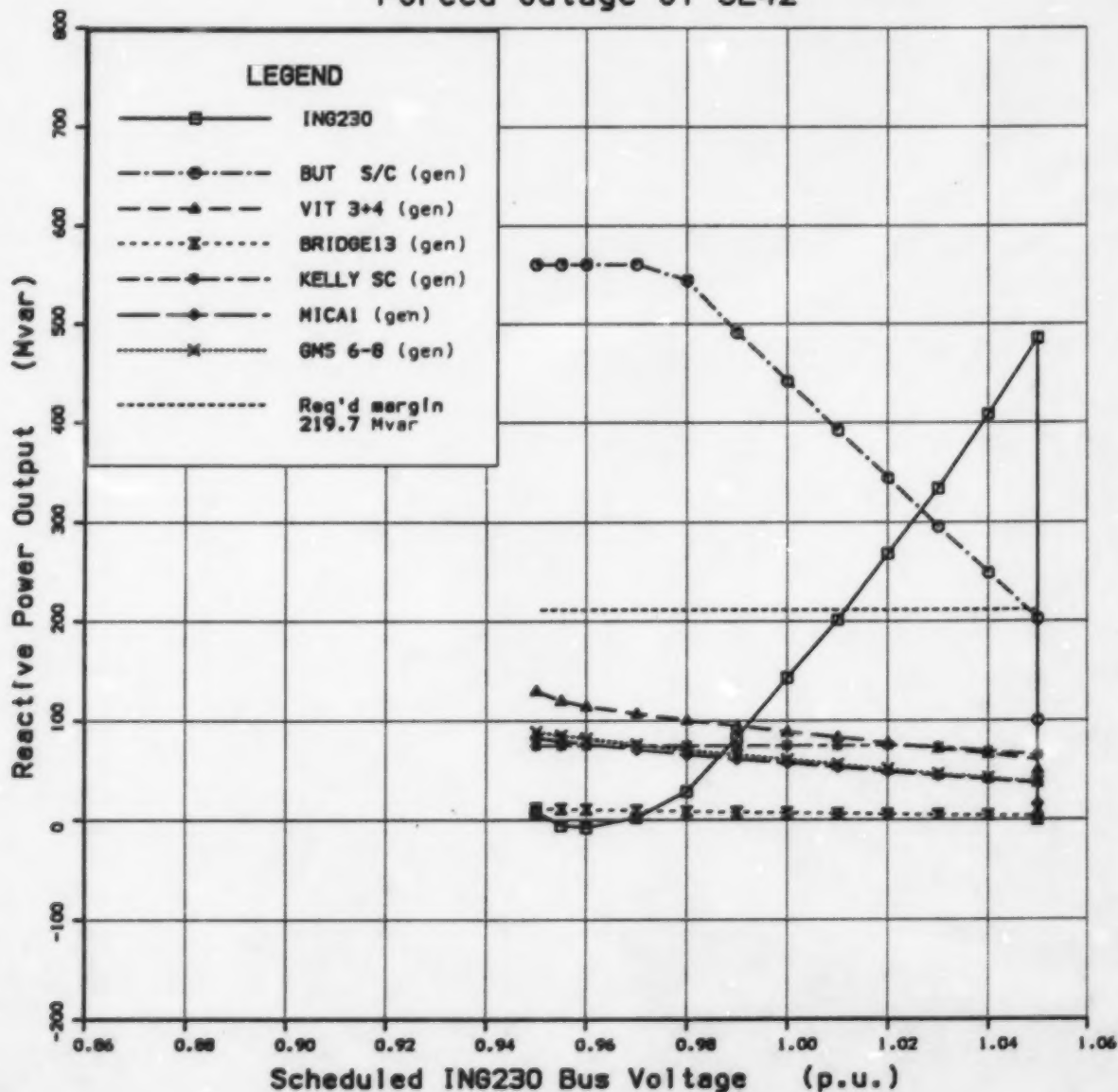


Post outage unsupported voltage: 0.991 p.u.
Bottom of curve: 0.950 p.u., -158.9 Mvar
Reactive reserve minus margin: -47.0 Mvar

FIGURE B6 Voltage Stability Study

P9202P; MAX PEACE, VI=1138; IPP CI=160 ; NO SITEC OR LCD;
REV1: EXPORTS: WKP=-254, ALCAN=675, TAUC=0, BPA=-120

Forced outage of 5L42



Post outage unsupported voltage: 0.969 p.u.
Bottom of curve: 0.958 p.u., -7.9 Mvar
Reactive reserve minus margin: -211.8 Mvar

Figure B7
Surplus Reactive Reserve vs LM+VI Load
Base Case: 1994/95 System

